NON-PUBLIC?: N
ACCESSION #: 9011270126
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Palo Verde Unit 3 PAGE: 1 OF 11

DOCKET NUMBER: 05000530

TITLE: Reactor Trip Due to Power Distribution Module Failure Causing All SBCS Valves to Open
EVENT DATE: 10/20/90 LER #: 90-007-00 REPORT DATE: 11/19/90

OTHER FACILITIES INVOLVED: N/A DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(ii), 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Thomas R. Bradish, Compliance Manager TELEPHONE: (602) 393-2521

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: JI COMPONENT: IMOD MANUFACTURER: F180
REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On October 20, 1990, at approximately 1230 MST, Palo Verde Unit 3 was in Mode 1 (POWER OPERATION) at approximately 100 percent power when a reactor trip occurred. A false steam header pressure signal caused the in-service (i.e. 7 of 8 valves) steam bypass control valves (SBCVs) to open causing an excess steam demand and the subsequent reactor trip. The resulting reactor po
er transient was terminated by the Core Protection Calculator (CPC). No other safety system responses occurred and none were required. The event was diagnosed as an uncomplicated reactor trip. At approximately 1245 MST on October 20, 1990, the plant was stabilized in Mode 3 (HOT STANDBY) at normal operating temperature and pressure. Subsequently, on October 22, 1990, APS Engineering determined that Unit 3 was in an unanalyzed condition that was outside its design basis. The Updated Final Safety Analysis Report Chapter 15 "Accident Analysis" assumed that only one SBCV would open due to a failure of the control

system.

The false pressure signal which caused the SBCVs to open was determined to be a result of a power distribution module failure in a Balance of Plant analog instrument cabinet. The root cause of the power distribution module failure was determined to be a fault diode. The module has been replaced. The failure of the diode was a random, low frequency component failure.

Similar events were reported in Unit 1 LERs 86-006 and LER 86-053, and Unit 3 LER 89-001.

END OF ABSTRACT

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

At approximately 1229 MST on October 20, 1990, Palo Verde Unit 3 was in Mode 1 (POWER OPERATION) at approximately 100 percent power.

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification: Automatic actuation of the Reactor Protection System (RPS)(JC).
Condition outside the design basis of the plant.

On October 20, 1990, at approximately 1230 MST a reactor (RCT)(AC) trip occurred due to a Variable Overpower Auxiliary Trip generated by the Core Protection Calculator (JC)(CPU) (CPC) which caused a low Departure from Nucleate Boiling Ratio (DNBR) trip signal. A momentary, false rapidly increasing steam header pressure signal caused the in-service (i.e. 7 of 8 valves) steam bypass control valves (V)(JI) (SBCVs) to open causing an excess steam demand and the subsequent reactor trip. At approximately 1245 MST on October 20, 1990, the plant was stabilized in Mode 3 (HOT STANDBY) at normal operating temperature and pressure. The event was diagnosed as an uncomplicated reactor trip. No other safety system responses occurred and none were required.

Prior to the trip, on October 20, 1990 at approximately 1229 MST Palo Verde Unit 3 was in Mode 1 (POWER OPERATION) operating at approximately 100 percent power when alarms were received in the Control Room (NA) and the in-service Steam Bypass Control System (JI) (SBCS) valves were observed to be modulating open. Control room personnel (utility, licensed) determined that a SBCS actuation was not required and placed the SBCS in the "emergency off" mode, which rapidly closed the SBCVs. Because of the excess steam demand and subsequent power increase, CPC Channel 'D' low DNBR trip signal was generated immediately followed by Channel 'D' high Local Power Density (LPD) and Channel 'C' low DNBR trip signals, satisfying the two-out-of-four trip logic for the RPS. This resulted in a reactor trip and subsequent main turbine generator (TA/TB)(TG) trip.

Immediately following the turbine trip, the operators (utility, licensed) returned the SBCS to service in order to maintain steam

pressure below the main steam (SB) safety valves (RV) setpoints. The SBCS responded properly by modulating the valves open and maintaining secondary pressure and primary temperature at the no-load setpoints.

The Control Room Supervisor (CRS) (utility, licensed) diagnosed the event as a reactor trip and entered the approved reactor trip procedure. At approximately 1245 MST, the plant was stabilized in Mode 3 (HOT STANDBY). No other safety system responses including Engineered Safety Features Actuations (JE)! occurred and none were required. The Shift Supervisor (utility, licensed) declared the event an uncomplicated reactor trip. No significant anomalies were noted in the control system or overall plant response to the event which adversely affected plant operation.

On October 22, 1990, during a review of the event after the unit restart, Engineering personnel (utility, non-licensed) raised a concern regarding the design basis for the SBCS as specified in the Updated Final Safety Analysis Report (FSAR). The Updated FSAR Section 10.4.4 "Turbine Bypass System" states that no single failure would result in excess steam releases. The Updated FSAR Section 15.1.4 "Inadvertent Opening of a Steam Generator Relief or Safety Valve" of Chapter 15 "Accident Analysis" assumed that only one Atmospheric Dump Valve (SB)(V) (ADV) or SBCV would open due to a failure of the control system. The inadvertent opening of more than one SBCV was not analyzed in the Updated FSAR. On October 22, 1990, APS Engineering determined that Unit 3 was in an unanalyzed condition that was outside its design basis.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

Not applicable - no structures, systems, or components were inoperable at the start of the event which contributed to this event.

D. Cause of each component or system failure, if known:

Engineering analysis and troubleshooting found that the initial alarms and spurious SBCV modulations were the result of a power distribution module (IMOD) failure in a Balance of Plant (BOP) analog instrument cabinet. The module failed in such a way as to cause a momentary, false rapidly increasing steam header pressure signal to be sent to the SBCS Master Controller (PMC). The controller then caused the in-service SBCVs to modulate open.

An Engineering root cause of failure investigation found that the Power distribution module failure was a result of a failed (i. e., shorted) diode. The diode failure was determined to be a random, low frequency component failure.

E. Failure mode, mechanism, and effect of each failed component, if known:

The diode failure in the power distribution module of the BOP analog instrument cabinet caused the modules's +15 volts DC power supply to short to the cabinet's common, thereby affecting power to the other components in the cabinet. The net affect of the diode failure and subsequent power perturbation manifested as 'zero' output from the various transmitters and modules contained in the cabinet. A fuse in the power distribution module opened as the failed diode loaded the +15 volt supply isolating the shorted condition. This allowed the various components to reenergize and return to their normal outputs.

When both Main Steam Header pressure current-to-voltage converters, located in the BOP analog instrument cabinet, re-energized, the steam pressure signals rapidly increased back to their normal outputs. As the false pressure signal increase approached the controller's setpoint, the controller demanded a modulation of the SBCVs. The SBCVs opened causing excess steam demand and the subsequent reactor trip.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no component failures with multiple functions were involved.

G. For a failure that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the train was returned to service:

Not applicable - no failures were involved which rendered a train of a safety system inoperable.

H. Method of discovery of each component or system failure or procedural error:

The failed power distribution module and shorted diode were

discovered during troubleshooting and the root cause of failure investigation performed after the event. There were no procedural errors which contributed to this event.

I. Cause of event

Engineering analysis and troubleshooting found that the initial alarms, the in-service SBCVs modulations, and subsequent reactor trip were the result of a power distribution module failure in a BOP analog instrument cabinet as described in Sections I.D and I.E. The root cause of the power distribution module failure was determined to be a faulty diode. The malfunction was determined to be a random low frequency component failure (SALP Cause Code E: Component Failure).

The root cause of Unit 3 being in a condition which was outside its design basis was a failure to comply with the interface requirements for the original system design (SALP Cause Code B: Design, Manufacturing, Installation Error). The design did not preclude a single failure in the power distribution module from affecting both steam pressure signal inputs into the SBCS. BOP instrumentation interface requirements specify that the two header pressure signals

are required to be independent signals powered from independent sources in the SBCS. However, these signals share a common connection at the current-to-voltage converters associated with the two signal loops.

These two root causes, in combination, caused the seven in-service SBCVs to open. No unusual characteristics of the work location (e.g., noise, heat, poor lighting) contributed to this event. There were no personnel errors which contributed to this event. There were no procedural errors which contributed to this event.

J. Safety System Response:

At approximately 1230 MST, the CPC generated a Variable Overpower Auxiliary Trip, which caused a CPC Channel 'D' low DNBR trip signal. The trip signal was immediately followed by Channels 'D', high LPD and Channel 'C' low DNBR trip signals, satisfying the two-out-of-four trip logic for the RPS. This resulted in a reactor trip and subsequent main turbine generator trip. There were no other safety system responses and none were required.

K. Failed Component Information:

The power distribution module was manufactured by Foxboro. The part number is 2AX-DP10/F. The Foxboro diode part number is N-2AX+DIO. The vendor was contacted for any information regarding their experience with failure of these modules. The vendor stated that no excessive failures had occurred for the modules and that the mean time between failure is approximately 30 years or longer. IEEE-500 "Industry Reliability Data" was also reviewed and supported the 30 year or longer mean time between failure estimate provided by Foxboro.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

The inadvertant opening of more than one SBCV was not analyzed in the PVNGS Updated FSAR. The Updated FSAR Section 10.4.4 "Turbine Bypass System" states that no single failure would result in excess steam releases. The Updated FSAR Section 15.1.4 "Inadvertent Opening of a Steam Generator Relief or Safety Valve" of Chapter 15 "Accident Analysis" assumed that only one Atmospheric Dump Valve (ADV) or SBCV would open due to a failure of the control system.

The Anticipated Operational Occurrence (AOO) analyzed in the Updated FSAR Section 15.1 is an inadvertent opening of one SBCV or ADV. The basis for this was the design requirement that no single failure would result in more than one of these valves opening. The Unit 3 trip demonstrated that a single failure, outside the SBCS, could result in all in-service SBCVs opening.

An analysis of actual plant conditions during the transient showed that the CPCs were effective in terminating the event prior to approaching fuel design limits. Data from the Core Operating Limit Supervisory System (COLSS), which maintains the initial conditions of analyzed events, showed that, for the event described in this LER, an 11 percent power margin existed from the COLSS DNBR limit at the initiation of the transient.

An analysis of the consequences of simultaneously opening eight SBCVs while at 102 percent power was performed. The inadvertent opening of the steam bypass control system valves (IOSBCSV) event results in an increase in heat removal by the secondary system greater than that previously analyzed in PVNGS Updated FSAR, Section 15.1, Revision 2 for an AOO. The IOSBCSV event was analyzed to verify that the minimum DNBR resulting from this event will not violate the SAFDLs. For this event,

the major parameter of concern is the minimum hot channel DNBR. This parameter establishes whether a fuel design limit has been violated and thus whether fuel cladding degradation might be anticipated. Those factors which cause a decrease in local DNBR are:

a. increasing coolant temperature
b. decreasing coolant pressure
c. increasing local heat flux (including radial and axial power distribution effects)
d. decreasing coolant flow

The IOSBCSV increases the rate of heat removal by the steam generators, causing a rapid cooldown of the reactor coolant system (RCS). Opening eight SBCS valves increases the steam flow by approximately 88 percent of full power steam flow. Due to the negative moderator temperature coefficient (MTC) assumed for this event, core power increases from the initial assumed value of 102 percent of rated core power to a value of 118 percent, at which time the reactor trips on CPC variable overpower. The feedwater control system, which is assumed to be in the automatic mode, supplies feedwater to the steam generators such that steam generator water levels are maintained.

Following the generation of a turbine trip on reactor trip, the feedwater control system enters the reactor trip override mode and reduces feedwater flow to 5 percent of nominal, full power flow. If the low steam generator (SG) level setpoint is reached due to continued steaming through the SBCS, an auxiliary feedwater actuation signal (AFAS) is generated and the auxiliary feedwater pumps will actuate to provide additional feedwater. The steam generators will continue to blowdown until the main steam isolation valves close on low secondary system pressure (820 psia). At this time, the SBCVs will be isolated. Thereafter, the RCS and steam generators will heat up and repressurize until the main steam safety valve (MSSV) opening set pressures are reached. Steaming will then resume through the MSSVs to remove heat from the RCS. If required, the RCS pressure will be limited by the primary safety valves (PSVs), such that RCS pressure will remain within 110 percent of design pressure.

The results of the analysis demonstrate that no SAFDLs would be exceeded for this event. The IOSBCSV event results in maintaining DNBR greater than 1.24 throughout the transient. The CPC provides adequate protection for excess steam demand events occurring at 100 percent power.

An analysis of events initiating from lower power levels was completed. The excess steam demand event at 95 percent power has been determined to be the bounding event. An initial power margin of 116 percent must be reserved by the Core Operating Limit Supervisory System (COLSS) at 95 percent power. This analysis requires that, for example, when the Required Overpower Margin (ROPM) is set at 115 percent, a 1 percent power margin penalty is required to be applied in COLSS. In the event COLSS is out of service the appropriate penalty will be applied to the CPCs to provide equivalent protection. Tuning of the CPC response during routine reload analysis may make this excess load event non- limiting and allow removal of any power margin penalty associated with it.

The Updated FSAR Section 15.1 identifies the most limiting accident for an Increase in Heat Removal by the Secondary System (Updated FSAR Section 15.1) to be a Main Steam Line Break, which results in limited fuel damage and acceptable offsite dose. When the circumstances of this event were compared to the Main Steam Line Break accident analysis, it was determined that the analyzed event bounds the actual plant occurrence. No safety limits were violated as a result of this event. There were no safety consequences resulting from this event based on the conditions existing at the time of the event.

III. CORRECTIVE ACTION:

A. Immediate:

APS investigated the Unit 3 trip in accordance with the requirements of the Incident Investigation Program.

The power distribution module was removed and successfully retested after card replacement. No other equipment malfunctions were discovered. Based on the Incident Investigation Team review, unit restart was authorized by the Plant Manager in accordance with approved station administrative control procedures. The unit entered Mode 2 at 1632 on October 21, 1990, and was placed back on the grid at 0313 on October 22, 1990.

Subsequent review of this event determined that the plant was outside its design basis. An interim Justification for

Continued Operation (JCO) was issued on October 24, 1990 providing APS's basis for interim operation of the Palo Verde units until a formal JCO could be provided. The interim JCO included the conservative compensatory action of stationing an operator at the SBCS panel to

terminate any spurious actuation, pending the completion of additional analysis and the insertion of a 5 percent power penalty factor in COLSS.

B. Action to Prevent Recurrence:

APS Engineering performed a root cause of failure investigation. The results of the investigation are described in Section I.D. Additionally, Engineering contacted the manufacturer of the diode. Per discussions with the manufacturer, above average failure rate has not been experienced. Based on the low failure rate, no further actions for the failed diode are planned.

On November 1, 1990, a formal JCO, including a safety analysis for the quick opening of eight SBCVs from 102 percent power was issued. The results of the analysis demonstrated that SAFDL would not be exceeded for this event. Further evaluation of other Chapter 15 events that could be affected by the SBCS failure will be completed by November 23, 1990. Upon completion of this evaluation, APS will submit the Updated FSAR Chapter 15 analysis for the inadvertent opening of more than one SBCV to the Nuclear Regulatory Commission.

APS will complete a detailed design review to identify and evaluate corrective actions for any other potential si
gle
failures of SBCS interfaces which could cause a spurious opening of more than one SBCV. Engineering will evaluate corrective actions to establish main steam header pressure transmitter independence as part of the SBCS design review. The purpose of this review is to evaluate the need for plant modifications which would establish the interface requirements and ensure reliable operation of the SBCS. In addition, APS will complete a Failure Modes and Effects Analysis (FMEA) study on the SBCS interfaces.

IV. PREVIOUS SIMILAR EVENTS:

Previous similar events involving SBCS malfunctions resulting in excess steam flow have been reported in Unit 1 LER 86-006, LER 86-053, and Unit 3 LER 89-001. As discussed in Section I.I, the cause of the event reported in this LER (530/90-007) was a random component malfunction of a diode. Since different components were involved, the previous corrective actions would not have prevented this event.

As reported in Unit 1 LER 86-006, during a 100 percent unit load rejection test and subsequent failure of the fast bus transfer system, power was lost to a non-class 1E 120 VAC distribution panel. When power was restored to the panel, the SBCS opened eight valves in response to a manual modulation demand created by the power restoration. The cause of the valves opening was the transfer of the master controller to manual from automatic following restoration of power to the SBCS. When the controller was reenergized it transferred to the manual mode of operation with a demand signal equal to 33 percent (equal to the automatic control signal in effect at the time of the power loss/recovery). The reason the master controller had a demand signal present was that the manual setpoint tracks the automatic demand signal to produce a bumpless transfer from automatic to manual. A Plant Change Request (PCR) was initiated to evaluate the problem. The PCR was later cancelled on September 22, 1986 for the following reasons:

a. SBCS troubleshooting revealed that power interruptions exceeding approximately 2 seconds result in a system transfer to "emergency off," a "fail safe" mode prohibiting anomalous system behavior.

b. Successful testing of Fast Bus Transfer in Unit 2 at 100 percent power, September 11, 1986, minimized the potential for a sustained loss of power to the non-class distribution system without a coincident power interruption to the class system as well.

As reported in Unit 1 LER 86-053, a reactor trip resulted from the loss of four steam flow inputs to the SBCS when a circuit board in the Emergency Response Facility Data Acquisition and Display System (IU) (ERFDADS) was grounded. This caused eight SBCVs to quick open. The resulting transient was terminated by a Main Steam Isolation Signal (JE). This problem was addressed in three ways: (1) the extender board which caused the grounding was modified to isolate the inputs from any ground source; (2) warning placards were posted in the equipment cabinets reminding personnel of the potential for a reactor trip when work was being performed in the cabinet; (3) a Design Change Package (DCP) was written to split the steam flow signals among various boards thereby eliminating the potential for single failure. The DCP work is complete in Units 1 and 2. The DCP is scheduled to be completed in Unit 3 during the next refueling outage.

As reported in Unit 3 LER 89-001, following a large load rejection as a result of a turbine generator trip the SBCS initiated a quick open demand, as designed, the initial quick open signal was followed by multiple quick openings of four of the eight SBCVs. This resulted in a reactor trip and safety system actuations. The quick open signals after

the initial signal were caused by a failed permissive timer card in the SBCS. This problem was corrected by the replacement of the timer card.

The analysis for the SBCS malfunctions as an AOO for the events discussed above were not performed because, at the time, the events were assumed to be bounded by the Main Steam Line Break analysis of the Updated FSAR Chapter 15.

ATTACHMENT 1 TO 9011270126 PAGE 1 OF 1

Arizona Public Service Company
PALO VERDE NUCLEAR GENERATING STATION
P.O.BOX 52034 PHOENIX, ARIZONA 85072-2034

192-00704-JML/TRB/KR
JAMES M. LEVINE November 19, 1990
VICE PRESIDENT
NUCLEAR PRODUCTION

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Mail Station P1-37
Washington, DC 20555

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Unit 3
Docket No. STN 50-530 (License No. NPF-74)
Licensee Event Report 90-007-00
File: 90-020-404

Attached please find Licensee Event Report (LER) No. 90-007-00 prepared and submitted pursuant to 10CFR50.73. In accordance with 10CFR50.73(d), we are forwarding a copy of the LER to the Regional Administrator of the Region V office.

If you have any questions, please contact T. R. Bradish, Compliance Manager at (602) 393-2521.

Very truly yours,

JML/TRB/KR/dmn

Attachment

cc: W. F. Conway (all with attachment)
J. B. Martin
D. H. Coe
A. C. Gehr
A. H. Gutterman
INPO Records Center

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